Attachment 13

SCHEDULED FOR ARGUMENT NOVEMBER 2, 2001

Nos. 00-5404, 00-5405 (consolidated)

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA and
AMERICAN PETROLEUM INSTITUTE,

Plaintiffs-appellees,

v.

DEPARTMENT OF THE INTERIOR, *et al.*,

Defendants-appellants.

On Appeal from the United States District Court
for the District of Columbia

BRIEF *AMICUS CURIAE* OF THE CALIFORNIA STATE CONTROLLER FOR THE STATE OF CALIFORNIA IN SUPPORT OF DEFENDANT-APPELLANTS, THE UNITED STATES DEPARTMENT OF THE INTERIOR, *ET AL.*

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June 12, 2001

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GLOSSARY

DOI:	The United States Department of the Interior
FERC:	Federal Energy Regulatory Commission
FOGRMA:	Federal Oil and Gas Royalty Management Act
IBLA:	Interior Board of Land Appeals
IPAA:	Independent Petroleum Association of America
MMS:	Minerals Management Service
SCO:	State Controller's Office

INTEREST OF *AMICUS CURIAE*

California receives a percentage of the royalties owed on oil and gas production from federal lands in and offshore its borders. 30 U.S.C.§191; 43 U.S.C. §1337(g). Under State law, these revenues are earmarked for public education. The State Controller is the constitutional, elected official responsible for assuring that monies due the State, including federal funds, are properly accounted for and collected. As such, the State Controller's Office (SCO) operates under a delegation of audit authority from the Department of the Interior (DOI). Federal Oil and Gas Royalty Management Act, 30 U.S.C. §1735(FOGRMA).

California has a long history of involvement in the federal royalty program.[1] As *Amicus*, SCO brings to the case considerable knowledge about both the program and lessee practices; experience that will assist this Court's decision. In SCO's opinion, the district court ignored the historical context of DOI's actions and misunderstood commonly used oil and gas terms, leading it to get the applicable law exactly backwards. SCO supports the positions of the United States and the *Amici* Tribes and, to the extent possible, will not repeat their arguments.

BACKGROUND OF HISTORICAL FACTS

This case must be viewed within the context of the decades long struggle between the oil and gas industry and the federal, State and Tribal governments over the proper payment of royalties. The debate can be summarized simply: federal lessees want to pay royalties on the net amount realized from their sales, and the governments want to collect royalties on the fair market value of production.

In the early 1980s, States, Tribes, Congress, the General Accounting Office, and a DOI Blue Ribbon Commission found that federal oil and gas lessees were not paying what they lawfully owed the public in royalties. *See e.g.,* Commission on Fiscal Accountability of the Nation's Energy Resources, Final Report

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[1]*See* Notice of Intent of the California State Controller to File As *Amicus Curiae* in Support of the United States (June 1, 2001); Response to Appellees' Opposition to the California State Controller's Notice of Intent to Participate as *Amicus Curiae* in Support of the United States (June 12, 2001).

(January 1982); "More Specific Policies and Procedures Needed for Determining Royalties On Oil From Leased Federal Lands," B-118678 (GAO February 17, 1972). Lessees operated under an "honor system", under which royalties were typically remitted on the net amount realized from sales. H.R. Rep. No. 97-859, 97th Cong., 2d Sess., *reprinted in,* 1982 U.S. Cong. & Admin. News 4268-4276. These lessee actions, of course, were contrary to law. The situation existed because of administrative neglect.

In response, Congress enacted FOGRMA. In FOGRMA, Congress did not change the nature of the public's royalty interest. Royalty, as Congress set out in 1920 under its first leasing law, was due on the "amount or value of the production removed or sold from the lease" *See* 30 U.S.C. §226. Rules and cases already existed on how royalties were to be calculated. For example: (1) "value" meant "fair market value," which was to be derived by considering a host of indicators, but never less than a lessee's "gross" proceeds;[2] (2) when "value" was determined away from a lease, a lessee could deduct the "reasonable, actual costs" of transportation, nothing more[3]; (3) a lessee was required, because of its duty to market, to assume the costs of placing production in marketable condition (*California v. Udall*, 296 F.2d 384 (D.C. Cir. 1961)), and (4) lessees could not deduct other costs incidental to marketing, such gathering[4], taxes[5], or broker commissions.[6]

What Congress did under FOGRMA was to strengthen DOI's enforcement authority by, *inter alia*, requiring more audits and delegation of audit authority to States and Tribes. Congress's aim was to assure that lessees paid in accordance with the established law and policy. It recognized that collecting what was owed might entail looking beyond the lease lines for uncollected value. *See* 30 U.S.C. §1713(a).

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[2] *United States v. General Petroleum Corp.*, 73 F. Supp. 225, 235 (S.D. CA 1946), *aff'd sub nom Continental Oil Co. v. United States*, 184 F. 2d 802 (9th Cir. 1950); 30 CFR 206.103 (1987).

[3] *See generally General Petroleum*, 73 F. Supp. 225; *Shell Oil Co.*, 70 I.D. 393, 396 (1963).

[4] *The Texas Co.*, 64 I.D. 76, 80 (1957).

[5] *Wheless Drilling Co.*, 13 IBLA 21 (1973).

[6] *General Petroleum*, 73 F. Supp. at 257.

DOI's audit program exposed a variety of means by which lessees understated or hid royalties. Beginning about 1985, lessees began arguing that these errors were nothing more than "honest mistakes" or "reasonable interpretations" of the rules. They clamored for more "certainty" and specificity.

The result was a rulemaking on how to calculate royalties for oil and gas that culminated in 1988[7]. It was in this rulemaking that DOI permitted lessees to calculate a transportation deduction by reference to FERC tariffs; a rule under which, in the hindsight opinion of the district court, seemed to authorize lessees to deduct more than their direct costs of transportation.[8] Yet, nothing in the rulemaking, or the record of this case, suggests that DOI was doing more than it thought it was doing – permitting a deduction for the reasonable, actual costs of transportation. DOI believed that deduction of tariffs was consistent with its "past and present practice generally to allow *only those costs which are directly related to transportation* of the lease production." 53 Fed. Reg. at 1211[oil]; 53 Fed. Reg. at 1261[gas](emphasis supplied). Industry represented to DOI that tariffs were equal to the reasonable, actual costs of transportation, and urged their use to reduce administrative burdens. *See e.g.*, 53 Fed. Reg. at 1261[gas]. DOI, in fact, rejected industry requests to extend transportation deductions to include costs not directly associated with transportation. *See e.g.,* 53 Fed. Reg. at 1212 [oil].

In the 1988 rules, DOI also addressed nondeductible costs. This was done primarily through the definition of "gross proceeds". For gas, the term was defined:

> "Gross proceeds" (for royalty purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of unprocessed gas, residue gas, or gas plant products

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[7] Final Rule, Revision of Gas Royalty Valuation Regulations and Related Topics, 53 Fed. Reg. 1230 (January 15, 1988); Final Rule, Revision of Oil Product Valuation Regulations and Related Topics, 53 Fed. Reg. 1184 (January 15, 1988). *Amicus* SCO will distinguish whether it is referring to the oil or the gas rulemaking in a parenthetical after the cite.

[8] All costs rolled into a tariff are not automatically acceptable as transportation deductions under these rules; deductions are simply reported by lessees, subject to audit. Even for arm's length transportation, which is often based on tariffs, the rules state that a reported deduction will be corrected where "the contract reflects more than the consideration actually transferred either directly on indirectly from the lessee to the transporter for the transportation." *See e.g.*, 30 CFR. 206.105(a)(ii)[oil]; 206.157(a)(ii)[gas].

> produced. Gross proceeds *includes, but is not limited to*, payments to the lessee for certain services such as compression, dehydration, measurement, and/or field gathering to the extent that the lessee *is obligated to perform them at no cost to the Federal Government or Indian lessor*, and payments for gas processing rights. Gross proceeds, as applied to gas, also *includes but is not limited to* reimbursements for severance taxes and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal or Indian royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of "gross proceeds."

30 CFR. 206.151 (emphasis supplied). A nearly identical definition applies for oil production, except that, for oil, gross proceeds also "*includes, but is not limited to*, reimbursements for harboring or terminaling fees." 30 CFR 206.101 (emphasis supplied).

There are several points to highlight about the definition of "gross proceeds". First, the list of nondeductible costs is not exhaustive. Second, all of the costs listed are necessary to market production. Third, while some of the examples fall within the marketable condition rule (*e.g.* , dehydration)[9], others do not (*e.g.*, gathering). Fourth, the list includes costs within "gross proceeds" that are not attributable solely to the intrinsic value of production as it emerges from a wellhead (*e.g.*, measurement). Fifth, the list includes costs within gross proceeds that are not incurred "at" the lease (*e.g.*, harboring). Sixth, value is based on "gross" not "net" proceeds; acceptance of the net sales amount after deduction of all costs no matter where the production was sold was rejected.[10] *See e.g.*, 53 Fed. Reg. at 1241 [gas].

That "gross proceeds" included certain "costs" in the calculation of royalties did not escape industry's notice. In language almost identical to that of the appellees in this case, lessees argued that the "laundry list" of services "allows MMS to confiscate the value added by post-production activities" (called

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[9] "Marketable condition" means product "sufficiently free from impurities." *See* 30 CFR 206.101 [oil].

[10] This is also reflected in DOI's definition of "net-back method" – a valuation methodology that only applies when royalty is determined based on a value distant from the lease. The only authorized deductions in conducting a net-back are for "transportation, processing or manufacturing." 30 CFR. 206.101 [oil]. Other definitions clarify what these terms do not include. For example, transportation allowance does not include gathering. *Id.* (definition of "Allowance"). In other words, in netting back to determine value, all costs incurred are not deductible.

"downstream" activities in this case) and required them "to do much more than place production in a marketable condition." 53 Fed. Reg. at 1194 [oil]; *see also* 53 Fed. Reg. at 1240-1241, 1252 [gas]. These arguments were rejected by DOI. 53 Fed. Reg. at 1194-1195[oil]; 53 Fed. Reg. at 1241[gas].

In the debate on the 1988 rules, it must be recognized that industry wanted DOI to use gross proceeds as the primary indicator of "value". There are, of course, other valid indicators of value. *E.g.*, 30 CFR. 206.102(c)(4)[spot prices, oil]. Most State and Tribal comments advocated use of more neutral, transparent means for determining fair market value, such as highest spot price, which would reduce disputes over whether a particular cost was part of "value" or was deductible. *See e.g.*, 53 Fed. Reg. at 1198-1201 [oil]. Interestingly, DOI was willing to assume, at industry's urging, that in making sales, lessees act in the mutual financial interest of themselves and the governments.

> MMS typically accepts this [the gross proceeds] value because it is well grounded in the realities of the marketplace where, in most cases, the 7/8ths or 5/6ths owner will be striving to obtain the highest attainable price for the oil production for the benefit of itself; the royalty owner benefits from this incentive.

53 Fed. Reg. at 1198 [oil]; 53 Fed. Reg. at 1247 [gas]. *See also e.g.*, 53 Fed. Reg. at 1231 [gas] ("The MMS does believe that the vast majority of lessees act prudently in contract negotiations..."). This language is virtually identical to the definition of the "duty to market". *See e.g., Libby v. De Baca*, 179 P.2d 263, 265 (N.M. 1947)(lessee must act as "a reasonably prudent operator, having in mind his own interests as well as that of the lessor, to market the product"); Merrill, Covenants Implied in Oil and Gas Leases, at 212-213 (2d Ed. 1940)(duty to market is the "duty to realize the highest price attainable by ... reasonable diligence"). The selection by DOI of the gross proceeds methodology was based on industry's assurances that their "duty to market" would result in the "highest attainable" revenues for royalty beneficiaries. In short, the 1988 rules are predicated on the duty to market.

It must also be underscored that the very allowance by DOI of a transportation deduction presupposes that sales may take place away from the lease,[11] while the "gross proceeds" definition presupposes the

[11]Transportation deductions are *only* allowed where value is determined at a point distant from the lease. *See e.g.*, 30 CFR 206.104 [oil].

inclusion in value of certain "post production" or "downstream" costs and/or reimbursements. In sum, although the 1988 rules were more detailed, they reflected DOI's prior practices on what was deductible and what was "cost free" to the lessor. Only two costs are deductible, transportation and gas processing.

Even though DOI largely acceded to industry's views on calculating royalties, the 1988 rules did not end the disputes. In fact, beginning in the early 1990s, matters got worse. Many States, Tribes and private royalty owners, and eventually the federal government, found that industry continued to underpay royalties. *See e.g., United States ex rel Koch v. Koch Industries, Inc.*, 57 F. Supp. 2d 1122 (N.D. Okla. 1999); *United States ex rel Johnson v. Shell Oil Co.*, 33 F. Supp. 2d 528 (N.D. Tex. 1999). Many of the devices used by lessees to understate royalties are similar to transfer pricing mechanisms, where profits are shifted to related entities, or to points in an otherwise integrated process, which are subject to less or no tax or royalty. *See* Lobel, *et al*, "Transfer Pricing and Oil Royalties" 84 Tax Notes 151 (July 5, 1999). Some companies believed that "inexperienced" government auditors would not understand how to sort out such complicated arrangements. *E.g.,* "ExxonMobil to Appeal $3.5 Billion Alabama Verdict in Royalty Dispute," Inside F.E.R.C.'s Gas Market Report 13 (December 22, 2000). Use of these devices was accompanied by lessee refusals to turn over documents for audit. *See e.g., Shell Oil Co. v. Babbitt*, 125 F.3d 172 (3d Cir. 1999).One common device, for example, involves companies spinning off their in-house marketing operations to affiliated entities, or out-sourcing those activities, and then claiming a "downstream" marketing deduction. *E.g., Amerac Energy Corp.*, 148 IBLA 82 (1997). Lessees knew such costs were nondeductible if marketing was done in house.

As they did prior to1988, when underpayments were exposed, lessees claimed that the shortfalls were due to "honest mistakes" or "reasonable interpretations" of rules. *See e.g.,* "Making them pay: How big oil companies shortchange taxpayers on royalties," U.S. News & World Report 30, 31 (May 14, 2001). Industry again clamored for more certainty and specificity.

Also during the 1980s, the Federal Energy Regulatory Commission (FERC) began working to establish a more competitive gas market. Through FERC Order 436, FERC "began regulating pipelines as open access transporters and requiring nondiscriminatory transportation." Final Rule, Amendments to Transportation Allowance Regulations for Federal and Indian Leases To Specify Allowable Costs and Related Amendments to Gas Valuation Regulations, 62 Fed. Reg. 65753 (December 16, 1997). Federal lessees knew as early as 1985, the date of Order 436, the direction FERC was heading, which may explain their push to increase royalty deductions, including for the costs of off-lease services. 53 Fed. Reg. at 1252 [gas]. FERC's orders, in and of themselves, had no direct impact on lessees' royalty obligations, although more lessees may have begun to sell gas to more distant markets. If they chose to sell "downstream", however, it was DOI's intent under the 1988 rules to let them deduct the "reasonable, actual costs" of transportation, but to deny deductions for the type of marketing costs listed in the "gross proceeds" rule.

From DOI's and the State and Tribal standpoints, the end result of FERC's efforts – FERC Order 636 – was an eye opener. FERC "unbundled" the cost components that previously had been rolled into a lump sum charge. What was hidden became transparent; auditors recognized for the first time that tariffs, which the companies assured them in 1988 included only the reasonable, actual costs of transportation, included many costs that DOI never intended to be deductible. Unfortunately, it can be assumed that some lessees knew in 1988 that their claims to DOI about tariffs were false.

DOI proposed a rule to clarify which of the newly unbundled tariff costs were nondeductible under the 1988 gas rules. DOI categorized the costs as either attributable to transportation and deductible, or to marketing and thus nondeductible. As the States and Tribes complained, where there was any doubt about a cost it was treated as deductible. 62 Fed. Reg. at 65754. For example, DOI allowed companies to deduct Gas Research Institute fees, which are used to fund research programs on natural gas topics. Although the fees do not easily relate to either transportation or marketing, DOI treated them as deductible because they are mandated by FERC. 62 Fed. Reg. at 65758. Long-term storage fees were disallowed as a deduction because, under statute, royalty is owed when production occurs, not when the sale occurs. 62 Fed. Reg. at 65759. Again, giving industry the benefit of the doubt, however, the cost of temporary 30-day storage was allowed as a deduction because such storage facilitates "real time" transportation scheduling and deliveries.

Id. [12]

DOI also modified the language in the marketable condition provisions of its gas rules to reflect the lessees' duty to "market gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government." 62 Fed. Reg. at 65762. Industry attacked this on the same grounds that it attacked the definition of "gross proceeds" in 1988 – that it requires lessees to include post-production costs as part of gross proceeds beyond marketable condition costs. 62 Fed. Reg. at 65755-65757. Although industry urged DOI in 1988 to accept gross proceeds because lessees "will be striving to obtain the highest attainable price" for the mutual benefit of them and the government, in 1997 industry called this regulatory re-statement of its own promise "bad public policy." *Id.* at 65755.

In reality, of course, the added phrase says no more than was said under the 1988 rules read as a whole. When a lessee chooses to sell in a distant market, it may deduct the reasonable, actual costs of transportation. However, as under the "gross proceeds" rule, other costs, whenever or wherever incurred, cannot be deducted. Industry is simply using whatever confusion existed with regard to tariffs – confusion that existed largely because of their 1988 misrepresentations that tariffs were equal to the reasonable, actual costs – to get a second bite of the apple on the deductibility of marketing costs.

ARGUMENT

I. The Statutory "Fair Market Value" Requirement Limits Allowable Cost Deductions.

DOI determined the deductibility of costs by reference to the cost's economic function in deriving fair market value. The district court rejected this approach in favor of drawing a line on a map. This line was drawn based on statutory language requiring lessees to pay royalty on "the amount or value of the production

[12] The district court referred to the distinction between long and short term storage as an example of "arbitrary'" categorization. *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp. 2d 117, 127 (D.D.C. 2000). SCO acknowledges that DOI rationally could have concluded that short term storage was nondeductible. At the same time, given that royalty is not due until 30 days after the date of production, DOI chose to give lessees leeway in recognition of certain transportation realities. Deduction of long term storage, however, is clearly at odds with DOI's long held construction of the statute, which was explained in detail in the final rule. 62 Fed. Reg. at 65759. *Cf. BWAB, Inc.*, 108 IBLA 250, 259 (1989)(royalty payable on date of production, not date of sale).

removed or sold from the lease." 30 U.S.C. §226(b)(1)(A). *Independent Petroleum Ass'n of America v. Armstrong*, 91 F. Supp. 2d 117, 125 (D.D.C. 2000)("*IPAA*").

The statutory term ignored by the district court in construing this phrase was "value." As a term of art, a royalty based on "value" is distinct from a royalty based on "sales price", "amount realized" or "net proceeds." *See e.g., Shamrock Oil & Gas Corp. v. Coffee*, 140 F.2d 409 (5th Cir.), *cert. denied* 373 U.S. 737 (1944). DOI has long recognized this distinction. *Wheless Drilling Co.*, 13 IBLA 21, 28 (1973). Thus oil and gas "values" are not, as suggested in the district court opinion[13], the sum of the producers total costs plus a reasonable profit. The costs incurred by the lessee, whether selling "at" the lease or elsewhere, neither enhance nor reduce the values at the market where the oil is sold. Those costs do not create market values. To paraphrase the courts, if Congress had intended to compute royalty on a net or cost basis, it would have used the language needed to achieve that result. *See Illinois Pub. Telcoms. Ass'n v. FCC.*, 117 F.3d 555, 562 (D.C. Cir. 1997). Indeed, one of the reasons Congress chose the term "value" was because of suspicions about sales prices being offered at lease sites. *See* S. Rep. 1392, 79th Cong., 2d Sess., p. 9 (May 29, 1946)(testimony of Acting DOI Secretary Chapman, citing cases where field prices did not represent value); Hearings Before the Senate Committee on Land and Surveys, 79th Cong., 2d Sess., p. 237 (May 7-9, 1946)(testimony of DOI Secretary Krug that "value" provides necessary discretion to deal with situation of arbitrary field market prices).

The authority cited by the district court to support its wellhead/lease cost line was *United States v. General Petroleum*, 73 F. Supp. 225, 235 (S.D. CA 1946), *aff'd sub nom., Continental Oil Co. v. United States*, 184 F.2d 802, 820 (9th Cir. 1950). However, the court in *General Petroleum* was presented with virtually every argument that is being made by appellees in this case, and each of those arguments was flatly

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[13] 91 F. Supp. 2d at 120. *Amicus* SCO notes that neither during the 1988 or 1997 rulemakings nor before the district court did industry even attempt to establish that any particular cost incurred by a lessee "enhances" the value established in the market. *Compare Garman v. Conoco*, 886 P.2d 652, 660 (Colo. 1994)(lessee burden to submit evidence proving enhancement). Indeed, the regulatory history of the tariff issue in this case alone shows why royalty issues and policies cannot be resolved on the basis of industry's self-serving factual representations.

rejected. In short, the district court misread that decision.

In *General Petroleum*, DOI alleged that the field prices for oil from the Kettleman Hills field were below value, which resulted in royalty underpayments. Looking at the statute, the court confirmed that the term "value" means the "fair market value" of the field production. 73 F. Supp. at 235. In order to determine the "value" of the oil from Kettleman Hills, however, the court looked to prices for oil of similar quality in a different field – away from the lease. The court adopted prices from competitive open markets far from the field in order to determine the value of Kettleman Hills oil. It then adjusted the open market values by *one factor*: location. For this it looked to the relative difference in cost between transporting Kettleman Hills oil to the refinery market as compared to the cost of transporting oil from the open market field to the refinery market. It recognized that the purchasers who make the market – those who "established the demand for an identified product"[14] – would place a greater value on a product nearer or more accessible to where it is needed, and made an economic adjustment to reflect that value difference. *See Id.* at 238-246; *Continental Oil*, 184 F.2d at 818-819.

It is the economic adjustment made by the court in *General Petroleum* that is the genesis of appellees' mantra that value is set "at the lease." Yet, not only did the court use an off-lease value, it also specifically rejected the claim that the value it chose should be reduced to reflect the sales-specific costs or risks lessees incurred in "downstream" marketing – this was irrelevant to an analysis aimed at deriving value. *Continental Oil*, 184 F.2d at 820. Oddly, it is the court of appeals discussion of this issue that the district court cited to support its opposing conclusion that all costs assumed by a lessee in making a "downstream" sale are deductible. *IPAA*, 91 F. Supp. 3d at 125.

In determining the value of wet gas, the court in *General Petroleum* also rejected a lessee claim that it was entitled to deduct a marketing commission incurred in arranging a sale. The valuation method used by DOI was "net realization" – under which the value of the wet gas "at" the lease was set by taking the price for the two commodities manufactured, often off-lease, from the gas and deducting only processing costs.

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[14] *California Co. v. Udall*, 296 F.2d at 388.

There was no question that the lessee paid the commission, but, for the court, the costs of a lessee's efforts to make a sale were "of no moment" to a determination of production value. 73 F. Supp. at 257. Similarly, the court, in rejecting an argument that DOI could not collect royalties on stored gas until that gas was sold, held that under the statutory language royalty "accrues as the gas is produced," not when the sale is made. *Id.* at 257 -258. Obviously, if the court believed that "value" required DOI to factor in all of the particular sales costs incurred, it could not have construed the statute in this manner.

The court in *General Petroleum* also dismissed another argument quite similar to one accepted by the district court in this case – that basing royalties on "downstream" values gives the government a "free ride". *IPAA*, 91 F. Supp. 2d at 120. One lessee in *General Petroleum* was not involved in setting the under-valued oil prices at Kettleman Hills; it argued that to force it to pay more than it actually received through its sale would unjustly enrich the United States. The court held that the lessee's contract and the statute obligated it to pay royalty on value; these controlled its debt to the public, not its sales contract[15].

In short, what the court recognized in *General Petroleum* was that the statute limited deductible costs because "value" involves an inquiry distinct from and, in fact, independent of, a lessee's sales receipts. This approach also reflects industry practice: in trades of production, oil and gas companies adjust values solely by reference to differences in the quality and location of the oil or gas traded. Certainly in making the trades, companies incur other costs – costs of evaluating the market, drafting the contract, etc. – but those costs are not reflected in the companies' own contract valuation formulas for the oil and gas itself.

In 1988, DOI opted to use gross proceeds as the primary indicator of fair market value. Yet in making that choice, DOI did not lose sight of the fact that its statutory mandate – which it could not change – was

[15] The court in *General Petroleum* also rejected the argument, often advanced by industry, that the government's option to take royalty in kind, rather than in value, restricts its ability to collect full value from a lessee whose contract sales price was below fair market value. *See Continental Oil Co.*, 184 F.2d at 816-817. Rather than limit a lessee's duty, at least one court has held that the in kind option places a higher trust duty on the operator in making sales. *Reserve Oil, Inc. v. Pengo Petroleum, Inc.*, 711 F.2d 951 (10th Cir. 1983)(working interest option). The fact that for a royalty owner, a lessee might incur nondeductible costs – thus *hypothetically* increasing what a royalty owner would get in value over what it might get in kind – is irrelevant. *Mesa Operating Ltd v. DOI*, 931 F.2d 318, 325 n.52 (5th Cir. 1991).

to collect royalty based on the "value" of production. It thus allowed adjustments for the reasonable, actual costs of transportation, but it rejected – through the very definition of gross proceeds – any further netting of costs that a lessee might incur, wherever they might have been incurred. As *General Petroleum* clearly demonstrates, those costs are not germane to a determination of fair market value and DOI's historic practices reflect that interpretation of the statute. The *General Petroleum* case simply does not support the district court's conclusion that cost deductions are determined by a line on a map.

II. Performance of Lessee Duties Is Cost Free To A Royalty Owner.

In holding that no duty to market exists under federal leases (*IPAA*, 91 F. Supp.2d at 127-130), the district court ignored basic principles of interpretation of oil and gas contracts; interpretations that support the public's royalty interests in this case. Nothing in the doctrine of *contra proferentem* even suggests that the government is not entitled to the benefit of its bargain.

By statute, the United States has a "royalty interest." A royalty interest is distinguishable from other types of lease interests because it is a non-cost, non-risk interest.[16] For example, there is no dispute here that lessees cannot deduct the costs of developing the lease. If, however, the landowner retained a "working interest", those costs would be deductible. *See* Williams & Meyers, Oil And Gas Law, Manual of Terms (2000)("Working Interest" as subject to all costs of development, etc). This difference in treatment is not a function of any express lease provisions allocating costs between the lessee and lessor. "Royalty interest," "Working interest" and the like are terms of art, the usage of which reflect the understanding of the parties. As a matter of lease interpretation, unless a "royalty interest" owner specifically agrees – through an express provision – to assume a cost, the cost cannot be deducted from the royalty payment.

The costs and risks that are free to the royalty owner relate to the obligations the lessee agreed to perform by entering into the lease contract. Despite the "skepticism" of the district court (91 F. Supp. 2d at

[16] *Garman v. Conoco, Inc.*, 886 P.2d 652, 656 (Colo. 1994). *See also* Discussion Notes, 5 Oil & Gas Rep. 979 (1956)("An overriding royalty interest is a free interest carved out of the oil and gas leasehold estate, which estate is also called the working interest. Clearly an overriding royalty interest is free of the usual costs of drilling, operating, and marketing, which costs must be borne by the owner of the interest out of which the override was carved.")

127), this includes implied obligations. That oil and gas leases contain implied obligations has been recognized since at least 1905 – well before Congress enacted the first mineral leasing law in 1920. *Brewster v. Lanyon Zinc. Co.*, 140 F. 801 (8th Cir. 1905). This reflects the common industry practice to avoid detailed specification of post-discovery lease obligations; a practice that continues today. 5 Williams & Meyers, Oil and Gas Law, §801 (2000)("Most lease forms in general use today ... are silent about the obligation of the lessee with respect to the conduct of operations after oil or gas is first discovered.") As a result, the courts imposed by implication those duties necessary to fulfill the expectations of the parties. As the court in *Brewster* explained, "implication is but another name for intention ....Whatever is necessary to the accomplishment of that which is expressly contracted to be done is part and parcel of the contract, though not specified." 140 F. at 809-811.

What a lessee "expressly contracted" to do under a federal lease is to pay royalties to the lessor. "Obviously production without disposition is futile. Thus the courts have developed the implied covenant 'to make diligent efforts to market the production in order that the lessor may realize on his royalty interest.'" *Darr v. Eldridge*, 346 P.2d 1041, 1044 (N.M. 1959)(citation omitted). *See also Frey v. Amoco Production Co.*, 603 So.2d 166, 175 (La. 1992)(lessor interest in highest obtainable return); Merrill, Covenants Implied in Oil and Gas Leases at 212-213 (2d Ed. 1940) (same). Implied duties stem from the more general contractual duties of cooperation and good faith performance. 5 William & Meyers, Oil and Gas Law §802.1 (2000). Lessees are held to a duty to take actions that foster, not frustrate, the expectation of the lessor. The duty to market thus flows naturally from the lessor's interest in the highest attainable return in royalties.

It is equally natural for the cost of the duty to market to flow to the party that has the obligation to perform. If the lessor is denied "a share" of the greater receipts "on the basis that he shares none of the costs and risks of ... marketing, one may assume all royalties are unfair." *Frey*, 603 So.2d at 178. As the court held in *Garman v. Conoco, Inc.*, 886 P.2d 652, 659-660 (Colo. 1994), the very recognition by industry that the performance of other implied obligations, such as the implied covenant to drill, are cost free to a royalty owner dictates that the the implied duty to market is also cost free to the royalty owner. That this holds true for federal leases was decided by this Court in *California Co. v. Udall*, 296 F.2d 384, 387-388 (D.C. Cir. 1961). Had there been no cost free duty to market implied in federal leases, there would be no cost free duty to place product in marketable condition. The marketable condition rule is simply one application of the duty to market to a particular type of marketing costs.

The marketing covenant does not result in a "free ride" for the lessor. The royalty owner gave up 7/8ths of the production under the land in order to receive the benefits of the lessee's expertise in developing, operating and marketing production from the lease[17]. *E.g., Wood v. TXO Production Corp.*, 854 P.2d 880, 883 (Okla. 1992). What the lessor gets in return is a smaller 1/8th interest and the promise by the lessee of diligence – to exercise its best business judgment "to realize the highest price obtainable." Merrill, *supra.*

These concepts demonstrate the fallacy of appellees' assertion that a federal lessee's duty to market ends at the lease line. Under their theory, if in the best business judgment of the lessee, the "highest price obtainable" is in the field market, the government gets its percentage of that price without deductions for the costs of evaluating markets and risks, and arranging the sale or other marketing activities. Yet, if in the best business judgment of the lessee, there is a price advantage to selling in a different market, the lessee, in appellees' view, gets to deduct *both* the cost of transportation and the otherwise nondeductible marketing costs. In other words, if there is a "higher price obtainable by reasonable effort" (Merrill, *supra*), the government must pay extra for the very diligence and prudence it gave up 7/8ths of the oil and gas under public lands to receive.

Appellees' claims that these principles are "new" to them is belied by the fact that, as royalty owners, their members take advantage of these concepts on a daily basis. *Shell Offshore Inc. v. FMP Operating Co.*, 1988 U.S. Dist. LEXIS 13084 (E.D. La. November 21, 1988), for example, involved a dispute between two companies over the deduction of certain costs from a royalty payment. Shell held an overriding royalty interest in a lease, although it had also expressly agreed to some deductions. FMP calculated payments to

[17] *See also* 53 Fed. Reg. at 1253 [gas](DOI rejects post-production cost deductions noting that the "environment" around the lease was known at time of lease issuance and factored into bids).

Shell as if it had a working interest. When Shell objected, FMP said it would not market Shell's gas.

In holding for Shell, the court rejected FMP's claim that the use of common terms was unimportant. "[O]verriding royalty" is not an "empty label", the court said, "[i]t is a useful substantive term which parties can employ to signify the existence of contractual conditions which would otherwise have to be described in minute detail." The relevant "detail", the court held, was that a "royalty" interest is a "non-cost bearing interest", unless there is an *express* agreement otherwise to assume costs. The fact that Shell had agreed to some costs did "not magically transform an otherwise overriding royalty interest into a working interest." Rejecting FMP's argument that Shell, a sophisticated company, did not need the protection of implied obligations, the court held that FMP had duty to Shell, as a royalty owner, to market.

As *Shell Offshore* demonstrates, the district court here got it exactly backwards. It looked for express provisions detailing the duty to market and its cost free nature, when, under traditional principles, these concepts attach because of the very nature of the government's interest. It put a higher burden on the government, purportedly found under the doctrine of *contra proferentem*, to be more explicit in drafting its leases than is required of the most sophisticated royalty owners in the world. The duty to market does not "expand[] the obligations of a private party to the direct benefit of the government" (*IPAA*, 91 F. Supp. 2d at 128); it simply extends to the public the same benefits that these private parties take advantage of when it is their royalty revenues at stake. What the district court did in this case to the government is exactly what the court in *Shell* refused to do to an industry royalty owner – transform its interest into a working interest.

CONCLUSION

For the foregoing reasons, *Amicus* respectfully asks this Court to reverse the decision and judgment of the district court in this case.

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

Pursuant to Fed. R. App. P. 32(a)(7) and Circuit Rule 32(2)(C), I certify that the foregoing brief is printed in proportionately spaced 11-point type and that, exclusive of the items exempted under Circuit Rule 32(a)(3) and according to the word-count application of Wordperfect 9, the brief is 6289 words.

CERTIFICATE OF SERVICE

I certify that on this 12st day of June, 2001, I caused to be served, by first class mail, postage prepaid, a true copy of the foregoing "Brief *Amicus Curiae* of the California State Controller for the State of California in Support of Defendant-Appellants, the United States Department of the Interior, *et al.*" on the following:

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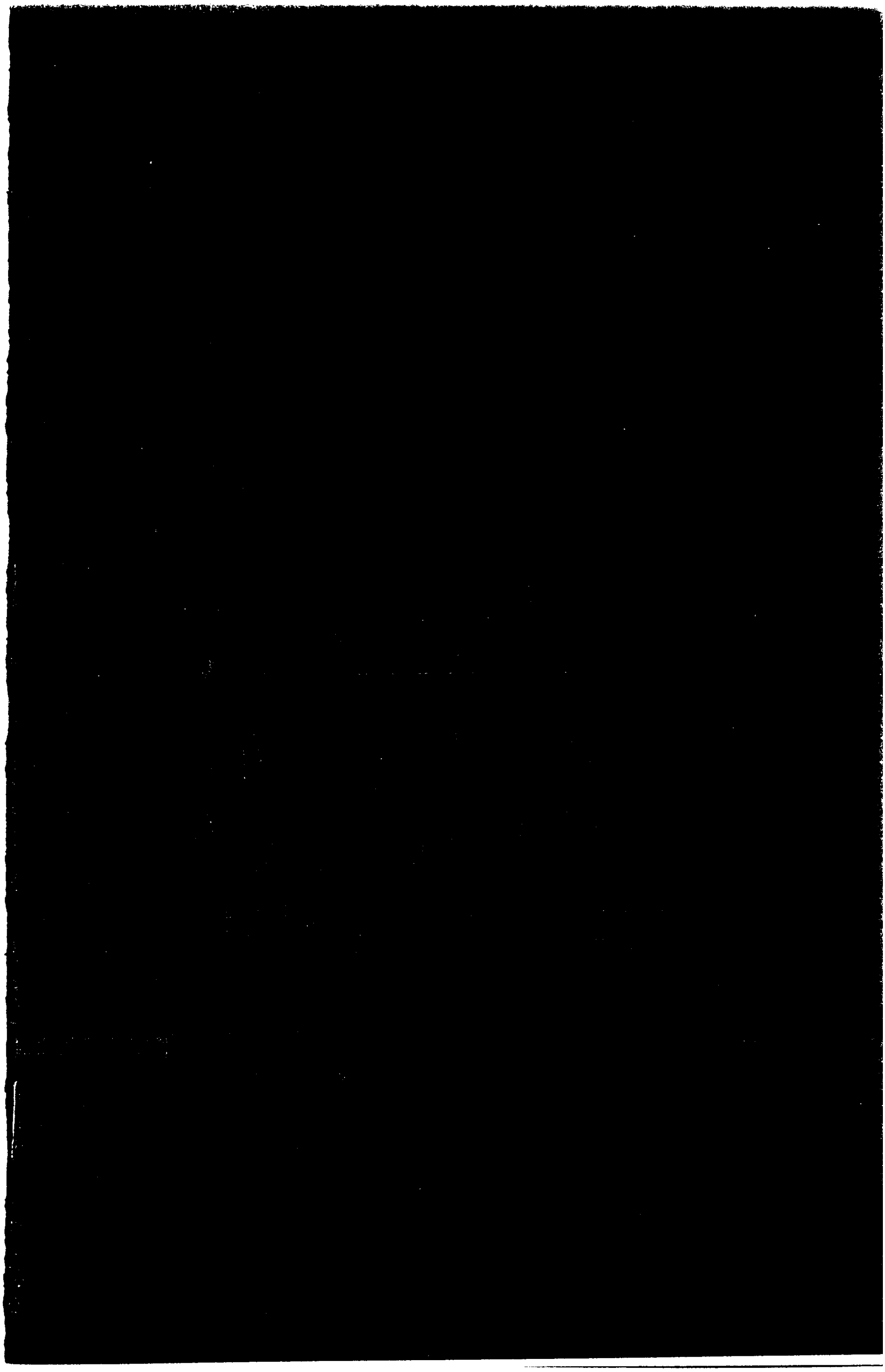
Attachment 14



IPAA's Modified Valuation Proposal

MIDSTREAM ACTIVITIES

Marketing

- Aggregating Volumes for Barrel Availability
- Satisfying Specialized Customer Quality Preferences
- Scheduling Monthly Crude Business through Contracted Companies and Pipelines
- Crude Movement Flow Schedule for Accounting
- Review Financial Analysis of Trades
- Review of Contracts and Other Marketing Arrangements vs.Current Markets
- Development of Monthly Market Differentials
- Obtain and Analyze Crude Oil Samples

Operations

- Contracting for or Providing Transportation
- Scheduling of Volumes
- Providing Pipeline Fill
- Tracking Volumes Delivered
- Providing Credit Services
- Constructing or Leasing Storage Facilities
- Scheduling Storage Volumes
- Maintaining Inventory
- Environmental and Safety Compliance

Risk Management

- Dealing with Price Fluctuations at or Upstream of Market Centers
- Risk or Loss of Pipeline Volumes
- Environmental Liabilities for Spills
- Risk of Purchasers' Default

Administration

- Contract Preparation and Follow through with Outside Company
- Contract Maintenance
- Royalty Bonus Development and Application
- MMS and Royalty Compliance
- Oil Price Development
- Inventory Reconciliation
- Disbursement Activities (Division Order, Tax, Legal)

Attachment 15

Lee E. Helfrich

From: Deborah.Gibbs.Tschudy@mms.gov
Sent: Tuesday, April 01, 2003 10:53 AM
To: Helfrich@LNLlaw.com
Subject: FW: Royalty Strategy Task Force Suggestions

Final cvr letter with attachme...

fyi

-----Original Message-----
From: Ken Leonard [mailto:Leonard@api.org]
Sent: Monday, March 24, 2003 2:15 PM
To: Knueven, Paul
Cc: Gibbs Tschudy, Deborah; Querques Denett, Lucy
Subject: Royalty Strategy Task Force Suggestions

Paul, at the MMS oil valuation workshops Debbie Gibbs-Tschudy asked for public input regarding transportation costs. On behalf of the Royalty Strategy Task Force and the four associations, attached to this letter is a list of 12 costs we believe are good examples of allowable transportation costs. Please make this letter and its attachment part of the public record of the workshops. Thank you.

Ken Leonard
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Please visit the New www.api.org

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V. Kenneth Leonard
Senior Manager, Upstream

March 24, 2003

Mr. Paul Knueven
Minerals Management Service
Minerals Revenue Management Program
P.O. Box 25165, MS 320B2
Denver, CO 80225-0165

Via email: Paul.Knueven@mms.gov

Dear Mr. Knueven:

I am writing in behalf of the Royalty Strategy Task Force, a coalition of independent, small and large producers and their trade associations, the American Petroleum Institute, Domestic Petroleum Council, Independent Petroleum Association of America, and U.S. Oil and Gas Association, to support the Minerals Management Service's evaluation of the effectiveness of its Crude Oil Valuation regulations.

We believe the agency should proceed with a Notice of Proposed Rulemaking to amend the regulations to address several technical issues that if resolved will result in a rule that is less complex and offers lessees reasonable certainty. Transportation costs are an important element of valuation and the MMS should explore opportunities for clarifying these costs by itemizing them in the rule. The current Gas Valuation Rule and its specification of allowable (and non-allowable) transportation costs is a good model. See 30 CFR 206.157(f).

During the MMS Workshop in Denver on March 4, 2003, Debbie Gibbs-Tschudy invited the public to provide for the record specific examples of transportation costs for the agency to consider as it examines this matter. The attachment to this letter lists examples of several allowable transportation costs, and definitions, that we believe should be included in a proposed rule amendment for public comment.

Please include these examples in the record of the Workshops. Please give me a call if you have any questions regarding these examples.

Sincerely,

VKL

Cc: Debbie Gibbs-Tschudy, Lucy Querques Dennet

Attachment

Examples of Allowable Actual Transportation Costs

Oil-Related Transportation Costs

1. **Third Party Transportation Costs – Tariffs and Contract Rates** – Fees paid to third parties for transportation services charged under a tariff or negotiated contract.

2. **Loss Allowance** – Fees paid to pipeline owners as prescribed in the rules and regulations (for common carrier systems) or in the terms & conditions (for proprietary systems). The loss allowance is typically taken in the form of a volume reduction (industry standard is 2/10ths of one percent) and is reflected as a volume adjustment on the pipeline statement. Lessees must convert the volume to value and divide by the total barrels moved in order to establish a per barrel cost.

3. **Quality Bank Administrative Fees** – Fees charged by pipeline owners for the administration of quality banks on their systems. The fees are itemized on pipeline statements.

4. **Line Fill Carrying Costs** – Lessee's cost of providing line fill as required by pipeline operators and/or terminal operators. The inventory volume has a market value that is carried on lessee's books as a capital line item.

5. **Terminal Fees** - Loading and/or unloading fees at terminals where oil moves from one form of transportation to another.

6. **Storage Fees (short term)** – Fees for storage incidental to transportation for less than 30 days required by transporter.

7. **Gauging Fees** – Fees for gauging services charged by carrier or 3rd party provider.

8. **Pump-over Fees** – Fees paid for pumping services provided by 3rd party or carrier.

9. **Transfer Fees** – Fees paid for actual physical delivery from one party to another party within a pipeline carrier's facilities.

10. **Scheduling Fees** – Fees paid to a third party scheduling service provider required by pipeline carrier, e.g. fees to Oil Distribution Services (ODS) at St James, LA.

11. **Special Product Charges** (high gravity deductions) – Fees paid for adjustments necessary to compensate for shrinkage when shipping high gravity crude oil (API 51 or higher).

12. **Letter of Credit Costs** – Lessee's cost of securing a letter of credit (as required by the transporter) when lessee makes a contract movement away from the lease on a proprietary pipeline system.

Attachment 16

CRUDE OIL VALUATION WORKSHOP (October 7-8, 1997)
HOUSTON

October 7, 1997- NOTES

9:00AM--hookup with Carla Wilson and Ed Johnson (Contractor) of IPAMS via telecon

Deborah Gibbs Tschudy

-- introductions/opening/housekeeping

-- next workshops -- 10/16/97 Bakersfield, California

-- 10/16/97 Casper, Wyoming

-- 10/21/97 Roswell, New Mexico

Ben Dillon

-- What is format of next workshops?

Deborah Gibbs Tschudy

-- Explain how rule works, give alternatives, ask for input--Federal Register notices available 10/8/97

Deborah Gibbs Tschudy

-- covered day's agenda and 10/8 agenda

-- everyone introduced themselves

-- will make minutes available for public/part of administrative record

Ben Dillon

-- IPAA wants to stress again their concern regarding time constraints/anything presented today is best they could do under circumstances. If MMS wants more information, hopes MMS will allow IPAA to have more time to further develop points. Wants Director/AD to look at IPAA work and consider in decision making.

-- IPAA has lots of experts in audience--wants them to be able to speak where appropriate.

Deborah Gibbs Tschudy

-- That is fine

Carla Wilson (IPAMS)

-- Thinks lease--based comparables should be 1st benchmark

-- (1) geographic area

(2) like quality (gravity within 10%, sulfur $>$.5% is sour, $<$ .5% is sweet; H_2S is separate category for comparables; proposes similar distillation curves (DOE established ± 5%), and any other industry--based characteristics.

(3) rather than like-quantities, use method of transportation because price is function of

Ben Dillon

-- MMS will be happy to learn IPAA did our homework assignment. For midstream activity we have compiled a list of costs. We have a handout for everyone to look at.

Debbie

Have you assigned values to these?

David Blackmon

-- Let's be clear on our concerns. The proposed rule establishes price at NYMEX with duty to market. This is a nationwide price. Does this mean all oil has to be sold in Cushing? Can you come back 5 years and tell us our lease price should have been uplifted to Cushing prices. We have genuine concerns about litigation for NYMEX. Then we need to discuss marketing costs Both the Mobil and Chevron settlements account for these costs.

Ben Dillon

-- Federal Regulations state mutual benefit of lessee with no cost deducted for marketing. But you are not willing to share in this cost. What is mutual about that? We have done a Survey on marketing activities (hand out). The range of costs is 7¢ to 15¢ per barrel. This is in its infancy. It's not scientific.

Deborah Gibbs Tschudy

-- Are all of these costs included in your deductible?

Ben Dillon

-- 7¢ - 15¢ may not account for all costs on this sheet.

Don Sant

-- How was the survey done? How do you put costs on risk management?

Ben Dillon

-- These costs are confidential and difficult to break down.

Ben Dillon/Jim McCabe

-- Don't you do these already? How much of this is incremental?

John Munsch

-- We looked at this a few years ago to see if someone could do this service cheaper than we could perform it ourselves. One company offered to perform these services their quoted fees fell in this range.

Ben Dillon

-- Value has not been assigned to each service. These are aggregated costs. We asked accountants to assign values. We have not heard back yet.

David Simpson

-- 7 - 10¢ per barrel are the price quotes we have received for these services, 8¢ is Total's cost. We decided not to hire out this service.

Greg Smith

-- What does midstream mean?

David Simpson

-- Anywhere other than at the well head.

John Munsch

-- MMS wants more value than lease value. Santa Fe engages in this activity away from lease but there are costs associated with this activity.

John Haley

-- These fees don't include market risk of taking possession of the production.

John Munsch

-- There's no way for accountants to come up with these costs.

Deborah Gibbs Tschudy

-- Would producer/refiners add costs to these lists?

Richard McPike

-- We would, if given time, add some costs.

Ben Dillon

-- Our list 7-15¢ is only part of the costs. It could be further refined if we were given more time.

Greg Smith

-- Any feel of number for services for oil sold at the lease?

Deborah Gibbs Tschudy

-- Some of these costs are the same as for sales at the lease.

Becky McGee
-- You will have to pay for contract attorneys to write lease sales.
-- Volumes would be greater downstream so costs would be spread over more barrels.

John Munsch
-- It's far simpler to sell at wellhead.

Greg Smith
-- Is price hedging part of the royalty basis? Is it fair to say these costs are not part of royalty uplift?

David Simpson
-- We don't have title to royalty share . We don't have this asset to hedge.

Bonn Macy
-- Hedging is insurance premium. It costs money.

Becky McGee
-- There seems to be some confusion about risk basis for price.

Dave Hubbard
-- What does royalty bonus development application mean? What are distribution tracing process costs?

Ed Johnson
-- Is time value of money covered? Risks of physical loss? Are these included in the price estimate?

John Munsch
-- These are not identified or segregated out.

Tom White
-- Letters of credit are real costs.

David Blackmon
-- The cost of insurance is easy to quantify.

John Munsch
-- Documentation of quality determination is a cost.

David Darouse
-- These are done for lease sales as well. What about operations in general?

John Munsch
-- Some of these costs will be the same for both.

Greg Smith
-- We appreciate your help on this.

Deborah Gibbs Tschudy
-- To states -- is this helpful for your earlier concerns?

Valdean Severson
-- Yes

David Darouse
-- Yes

Valdean Severson
-- Why is Alberta 5¢ a barrel?

Greg Smith
-- More competition for marketers?

Deborah Gibbs Tschudy
-- What is a picture of costs from IPAA on what is needed to market oil?

Ben Dillon
If MMS has no interest in going down this road, we didn't want to spend time on this.

Deborah Gibbs Tschudy
- The Department is not willing to move on deduction of marketing costs.

Ben Dillon
-- This decision puts our members at "disadvantage."

Don Sant
-- Who is at a disadvantage?

Ben Dillon
-- An affiliate with marketer.

Deborah Gibbs Tschudy
-- No one gets these costs. What's discriminatory?